NON-PUBLIC?: N
ACCESSION #: 9001170353
LICENSEE EVENT REPORT (LER)

FACILITY NAME: Sequoyah Nuclear Plant, Unit 1 PAGE: 1 OF 9

DOCKET NUMBER: 05000327

TITLE: Sequoyah Unit 1 reactor trip because of a high-high steam generator level.
EVENT DATE: 12/10/89 LER #: 89-035-00 REPORT DATE: 01/09/90

OTHER FACILITIES INVOLVED: DOCKET NO: 05000

OPERATING MODE: 1 POWER LEVEL: 100

THIS REPORT IS SUBMITTED PURSUANT TO THE REQUIREMENTS OF 10 CFR SECTION:
50.73(a)(2)(iv)

LICENSEE CONTACT FOR THIS LER:
NAME: S. W. Spencer, Compliance Licensing Engineer

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COMPONENT FAILURE DESCRIPTION:
CAUSE: SYSTEM: COMPONENT: MANUFACTURER:
REPORTABLE NPRDS:

SUPPLEMENTAL REPORT EXPECTED: NO

ABSTRACT:

On December 10, 1989, at 1051 Eastern standard time (EST) with Unit 1 in Mode 1, a turbine trip/reactor trip occurred. The trip resulted from a high-high feedwater level of 75 percent in the No. 3 steam generator (S/G). The trip was preceded by a secondary side transient and turbine runback to approximately 80-percent load as a result of a high level in the No. 3 heater drain tank (HDT). During the runback, a low feedwater flow was observed, and Main Feedwater Pump (MFP) 1A was placed in manual to boost feedwater flow to match steam flow. However, as the S/G levels recovered, No. 3 loop did not isolate until after the 60-percent setpoint, and the turbine/reactor trip occurred as the No. 3 S/G level reached 75 percent. Plant shutdown proceeded in an orderly manner consistent with procedures. A posttrip review teAm concluded that the trip was caused by a failure of S/G Loop 3 main feedwater regulating

valve to close and maintain Loop 3 S/G at a 60-percent level; a contributing cause was the inability of the MFP 1A to adequately respond to changing feedwater demands. The initiating event was the failure of level control valves to maintain proper levels in the No. 3 HDT. Corrective actions taken consisted of troubleshooting, repair, and/or adjustments to malfunctioning equipment. Longer-term corrective actions include Eagle 21 installation to improve operating margins.

At 2003 EST, an engineered safety feature feedwater isolation signal was actuated during posttrip testing when an alligator clip-type jumper fell off a terminal point. Interim corrective action consisted of issuance of a training letter to applicable personnel; long-term corrective action will be to evaluate a more positive method of connecting temporary jumpers.

END OF ABSTRACT

DESCRIPTION OF EVENT

On December 10, 1989, with Unit 1 in Mode 1 (100 percent reactor power, approximately 2,230 pounds per square inch gauge psig! and reactor coolant system (RCS) average temperature Tavg! at 578 degrees Fahrenheit F!) a reactor trip occurred at 1051 Eastern standard time (EST). The trip resulted from a high-high feedwater level of 75 percent in the No. 3 steam generator (S/G) (EIIS Code JB) as indicated by the first-out reactor trip annunciator. The trip was preceded by a secondary side transient turbine runback to approximately 80-percent load caused by a high level in the No. 3 heater drain tank (HDT).

Prior to the event while monitoring Unit 1 conditions in the main control room, the Unit 1 unit operator (UO) received an alarm for a low net-positive suction head on main feed pumps followed by an alarm for HDT bypass to Condenser C approximately 10 seconds later. The UO verified that Level Control Valve (LCV) 1-LCV-6-105B bypass to the condenser was opening and that the turbine was running back. Rod control was placed in auto, and the rods began stepping in. The runback to 80 percent was initiated by a high level in the No. 3 HDT caused by failure of the HDT LCV 1-LCV-6-106A and B to control level. As the runback was occurring, a low feedwater pressure condition was observed; therefore, the UO reduced the turbine an additional 5 percent (approximately) and placed the 1A main feedwater pump turbine (MFPT) in manual to boost the feedwater flow. By doing this, the UO was able to match feedwater flow and steam flow through the S/Gs. However, as the S/G levels increased, the steam pump valves closed after completion of the runback, causing steam flow to drop sharply. With these rapidly increasing S/G levels, the UO had to reduce the 1A MFPT speed manually. As S/G levels continued to increase, the main regulating valves started closing. The UO placed the main feed pump master controller in manual to maintain S/G levels while also matching feedwater/steam flow. As S/G levels continued to increase, the 60-percent narrow-range feedwater isolation setpoint was reached, and Nos. 1, 2, and 4 S/G loops were isolated. The UO and shift operations supervisor observed that the level in Loop 3 was still increasing, and the Unit 1 senior reactor operator placed the associated regulating valve 1-FCV-3-90 in manual at 25 percent of scale in attempt to reduce feedflow. However, a reactor/turbine trip occurred at a high-high level of approximately 75 percent in S/G No. 3.

As the unit was being stabilized following the trip at 1051 EST, the posttrip review team was put into place, and an assessment began. There were no known activities being performed on either the heater drain system or the feedwater system that could have had any impact on the event.

The review team divided the event into two separate transients, as follows:

1. Failure of the heater drain system, specifically 1-LCV-6-106A and B to maintain No. 3 HDT level, caused the turbine runback.

2. Failure of the feedwater regulating valve on Loop 3 to isolate S/G No. 3 level and the inability of 1A MFPT to respond to changing feedwater demands.

DESCRIPTION OF EVENT (Continued)

Each transient is discussed below.

Valve 1-LCV-6-106B is designed to maintain level in the No. 3 HDT. As level increases, 1-LCV-6-106A opens to allow increased No. 3 HDT pump flow, thereby reducing the level back to setpoint. As level in the No. 3 HDT increases beyond the capacity of 106A, 106B modulates as needed to maintain adequate HDT levels.

1-LCV-6-106B is also interlocked with pressure differential indicating Switch (PDIS) 1-PDIS-6-106B. The PDIS measures the delta P across the suction and the discharge of the HDT pumps. If delta P decreases to the point of pump runout, the PDIS causes LCV-6-106B to close, thereby ensuring the pumps do not cavitate.

At the start of the event, the main control room UO observed that Valve 1-LCV-6-105B was opening. This valve bypasses the HDT pumps and allows the HDT to discharge directly to the Condenser C. Because LCV-6-106A and B are designed to maintain HDT level, LCV-6-105A and B are only utilized when operation of LCV-6-106A and B is not sufficient to control HDT levels. The control circuit for LCV-6-105A and B initiate a turbine runback when the valves leave the fully closed position as an open signal indicates either 106A and/or B have malfunctioned or a transient has occurred upstream of the HDT, anticipating a partial loss of feedwater flow to the S/Gs.

The turbine building assistant shift operations supervisor was notified at the start of the transient. He verified that LCV-6-106A was fully open and 106B was closed, even after 105B had opened. Maintenance had recently been performed on LCV-6-106A and B, in accordance with Work Request (WR) B792987. The valves were rebuilt with a factory service representative present, and all testing had been satisfactorily performed. PDIS-6-106B that trips valve 106B closed on low delta P was checked and found not to be made up. The setpoint was verified against the values of 430 pounds per square inch differential implemented by the temporary alteration control form (TACF).

The control rod system was being operated in the manual mode prior to the event. Upon recognition of the event, the operators placed the rods in the automatic mode and the control system operated to drive the rods in. 1A MFPT failed to su
ficiently increase speed in the automatic mode upon initiation of the turbine runback and resultant secondary plant transient. The UO had to place the MFPT in manual and manually control the speed to maintain sufficient feedwater flow to prevent a low-low S/G level reactor trip.

The operator took manual control of feedwater pump master controls as levels continued to increase past the normal operating point approaching the 60-percent isolation setpoint. The feedwater regulating valve for Loop 3 is 1-FCV-3-90. Based on the UO interview and analysis of the applicable strip chart records, it appears that the regulating valve did not isolate at 60-percent level (in accordance with controller programming), but instead, the level continued to increase and the valve isolated at 64 percent. Loops 1, 2, and 4 isolated at 60-percent level. The cause for Loop 3 level to continue to increase could be caused by failure of the valve controller to respond

DESCRIPTION OF EVENT (Continued)

properly or a through-leak of the valve (valve does not fully seat, or allows passage of fluid through it while closed). Also, one of the two S/G level channels required for the 60-percent narrow-range feedwater isolation was identified as being 4-percent low with respect to the other Loop 3 S/G level channel.

During the posttrip interviews with personnel involved with the transient, several equipment anomalies were noted.

o The F-14 rod bottom light failed to illuminate following the trip even after the bulb was replaced.

o The nuclear instrumentation source range Detector N-32 scaler timer was reading double the indicated count rate.

o Flow Indicator 1-FI-62-138A did not initially indicate boration flow when boration was initiated as a result of the failed rod bottom light.

Subsequent to the trip on December 10, 1989, at 2003 EST, a feedwater isolation occurred on Unit 1 while testing the reactor trip breakers (RTBs) in response to the 1051 EST trip. The isolation occurred when a jumper, which had been placed to preclude a feedwater isolation signal, became disengaged during breaker cycling. The jumper had been installed to provide a signal that the RTBs were closed. When the jumper disengaged during breaker cycling, the open RTBs combined with Tavg of less than 554 degrees F, completed the logic to initiate a feedwater isolation signal.

CAUSE OF EVENT

The cause of the reactor trip was the failure of Loop 3 main feedwater regulating valve to close and isolate feedwater flow to the Loop 3 S/G at a 60-percent narrow-range level. A contributing cause was the failure of main feed pumps to adequately respond to changing feedwater conditions. Several transients occurred in the secondary plant supplying suction to the mainfeed pumps. Adequate response to these rapidly changing conditions did not occur within the feed pump control system.

The cause of the feedwater isolation was that during testing, an alligator clip-type jumper became disengaged; alligator clip jumpers cannot provide total assurance of sustained positive connection for all applications.

ANALYSIS OF EVENT

Based on the following discussions of plant response during and after the trip, plant systems and parameters responded consistent with responses described in the Final Safety Analysis Report (FSAR), and accordingly, the event did not adversely affect the health and safety of the public.

ANALYSIS OF EVENT (Continued)

Reactor Coolant System (RCS) Temperature

Pretrip Tavg was at or about 578 degrees F. Posttrip Tavg declined initially to 550 degrees F following the reactor trip. The operator worked within the guidelines of Emergency Procedure ES-0.1, "Reactor Trip Response." Tavg subsequently declined to 547 degrees F and stabilized. RCS temperature response, as a result of this trip, was within the bounds of the accident analysis.

Heatup/Cooldown Limits

Technical specifications (TSs) limit cooldown rate to 100 degrees F in any 1-hour time period. In accordance with the strip charts reviewed, temperature dropped smoothly with no perturbations during or after the event to 547 degrees F. The 100-degree limit was not exceeded, and no heatup was experienced relative to this event. Pressurizer Level

Pressurizer level was approximately 58.5 percent prior to the trip. Response of the pressurizer level to the transient closely paralleled that of RCS pressure and temperature. The pressurizer level drop initially attained during this event was 25 percent. The level increased and stabilized within limits of the control system and within the bounds of the accident analysis.

Feedwater Flow

Feedwater flow was steady for 100 percent power and all four main feedwater regulator valves were in automatic before the trip. Low net-positive suction head at the main feed pump was annunciated in the control room as required in the FSAR, Section 10.4.7.1.3. High level in the No. 3 HDT was indicated in the control room by a turbine runback to 80 percent when the drain tank to condenser Valve 6-105 had left its fully closed position in accordance with FSAR, Section 10.4.9.3. The level in the No. 3 HDT, in accordance with FSAR, Section 10.4.9.2, is maintained within the proper range by the modulating LCVs 6-106A and

6-106B. These valves are located at the discharge of the No. 3 HDT pump. Valves 6-106A and 6-106B failed to control the No. 3 HDT level resulting in the opening of Valve 6-105.

Turbine runback caused the steam dumps to open resulting in a transient and steam flow--feedwater flow mismatch (low feedwater flow). The two main feedwater pumps in accordance with the FSAR, Section 10.4.7.1.2, are capable of delivering feedwater flow under all expected conditions, and pump speed is automatically adjusted. Main feedwater Flow A failed to increase rapidly enough, and the operator had to take manual control. After the runback, the steam dumps closed, and S/G levels began a rapid increase due to the steam flow decrease. Numbers 1, 2, and 4 S/G levels increased to the 60-percent level and isolated while No. 3 isolated at 64-percent level. The water level in No. 3 S/G continued to increase until the 75 percent level was reached, and the turbine tripped.

Auxiliary feedwater (AFW) started as designed following the trip, and flow to the S/G from AFW continued at greater than 440 gallons per minute per S/G as expected. Manual control of AFW was taken. TSs and FSAR requirements and analysis were not challenged.

Steam Pressure

Pretrip S/G pressure varied from 850 to 860 psig. Posttrip S/G pressures increased to slightly over 1,000 psig because of the turbine trip. Steam pressure stabilized to no-load pressure as Tavg went to 547 degrees F. TS and FSAR requirements and analysis were not challenged.

Containment Pressure/Temperature Radiation

No perturbations were observed in containment pressure, temperature, or radiation. TS and FSAR requirements and analysis were not challenged.

Forced/Manual Circulation

All reactor coolant pumps continued to maintain flow postreactor trip; therefore, forced flow was not lost, and no FSAR assumptions-were challenged.

Reactor Power

Preevent reactor power was being maintained at 100-percent rated thermal power (RTP). Upon initiation of the turbine runback, the turbine reduced the reactor power to approximately 80-percent RTP. Upon receipt of a turbine trip above 50 percent nuclear instrumentation system power, a reactor trip signal was generated. Upon receipt of the reactor trip signal, the shutdown and control banks dropped into the core, reactor power rapidly decreased, and the unit was brought subcritical into Mode 3.

The short delay (approximately 10 seconds) in control rod insertion following the event resulting from preevent operation in the manual mode is not considered to have contributed significantly to the secondary side transient. The reactivity contributions of the rods for the short period of time was insignificant.

Shutdown Margin

Pretrip, the reactor was operating above the minimum insertion limits, and by definition, adequate shutdown margin was available.

Following the trip, expected cooldown occurred as previously discussed. Adequate shutdown margin was maintained in accordance with ES-0.1 and Surveillance Instruction (SI) 38, "Shutdown Margin," verified reactivity balance at 1201 EST. TSs and the accident analysis were not violated.

ANALYSIS Continued)

RCS Pressure

Prior to the event, RCS pressure was 2,240 psig. When the reactor trip occurred, the pressurizer pressure rose to 2,275 psig, then dropped to 2,078 psig within approximately 1 hour of the trip. These values are consistent with the values shown in the FSAR Figure 15.2.7-9, "Loss of Load From 52% Power with Pressure Control, Minimum Feedback." As discussed in the FSAR, Section 15.2.8, the AFW system was capable of removing enough residual heat to prevent overpressurization of the RCS. Therefore, the accident analysis was not challenged.

Steam Flow

Steam flow was steady at an expected value prior to the trip and dropped rapidly upon the turbine trip. Steam flowed to the steam dumps during the turbine runback and through the atmospheric relief valves following the trip. Steam flow response was bounded by the accident analysis.

S/G Level

Prio
to the event, levels in all four S/Gs were steady at 44 percent. At the outset of the transient, all four S/G levels dropped. S/G 3 went the lowest to 18.5 percent. Eighteen percent is the low-low level reactor trip setpoint. The other S/Gs dropped to between 20 percent and 26 percent. The levels then increased because of the operator taking manual control of the 1A MFPT and Tavg being satisfied to the point of not requiring steam dumps. With the steam dumps closed, steam flow decreased allowing the feed flow to increase S/G levels. The regulating valves and main feedwater pump (MFP) response was inadequate to control levels at normal operating point. The operator took manual control of the MFP master controller to reduce feedwater flow to the S/Gs. Levels rose to the single loop isolation point of 60-percent level when S/Gs 1, 2, and 4 isolated. S/G 3 did not isolate until 64 percent. The hydraulic characteristics of the feed header are such that as single loops isolate, the pressure in the header increases, and additional flow goes to the open loops. This being the case and Loop 3 being the last to get a loop isolation, Loop 3 would have received additional flow contributing to raising the level to 75 percent of the turbine trip/feedwater isolation setpoint.

The high-high level turbine trip and main feed isolation occurred as designed upon receipt of initiating signals.

The plant equipment associated with feedwater isolation responded in accordance with design. The plant was in a stable condition without use of feedwater; therefore, the isolation did not result in any system transient or anomalous equipment operation. SI-93 is only performed with the plant in a shutdown condition and after the RTBs have been opened; therefore, this incident could not result in a condition that could cause a plant transient.

CORRECTIVE ACTION

Corrective Action for the Reactor Trip

The following corrective actions were taken to ensure the plant was ready for restart and 100 percent power operation.

1. Troubleshooting, repairs, and adjustments were completed on the Loop 3 main feedwater regulator valve, and the 60 percent S/G narrow-range Loop 3 isolation circuitry to ensure proper valve

closure on 60 percent S/G narrow-range level. Even though Loop 3 main feedwater regulating valve did not close until 64 percent, the 4-percent difference was within the design tolerances.

2. Instrument Maintenance immediately verified Rod F-14 was on bottom, and a WR was written to have the F-14 rod bottom light repaired.

3. The N-32 scaler timer was repaired.

4. Subsequent cycling of the valve (1-FCV-62-138A) cleared an apparent blockage, and Operations verified that flow existed through the emergency borate (non-TS) flow path. A WR was written to perform further investigation.

5. Troubleshooting verified that the Loop 3 main feedwater regulating valve did not have excessive leak-through when main control room indication shows the valve on seat.

6. Troubleshooting of the A MFPT controls was completed to ensure correct calibration. No apparent deficiencies were identified.

7. Troubleshooting of the No. 3 HDT level controls was completed to ensure correct operation of the 6-105 and 6-106 level control loops. The level indicating Controller 6-106 was checked and found to only supply a maximum of 6 psig output signal. This means that there was only partial stroke of the A valve and no stroke of the B valve. The controller was recalibrated that resulted in the 6-106 valves stroking on demand, as required by the plant design.

8. The proper operating position of 1-LCV-6-106B at 100-percent RTP has been set with input from the vendor such that 106A and B now more equally share the load.

9. The proper setpoint of 1-PDIS-6-106B was determined and calibrated in accordance with a TACF.

10. Operations has verified that procedures require 1-HS-6-106B (1-PDIS-6-106B reset switch) to be depressed (reset) prior to relying on 1-LCV-6-106B for level control.

As long-term corrective actions, TVA will evaluate the need for No. 3 HDT alarms that will alert the operator of a high or low level in the HDT before the bypass to condenser valves open and before the HDT pumps loose suction due to low tank level.

CORRECTIVE ACTION (Continued)

Long-term corrective actions also include implementing Eagle 21 during the upcoming Cycle 4 refueling outage, which will lower the low-low S/G level reactor trip setpoint to 14.7 percent. The control systems for the plant were designed using the initial low-low level setpoint of 10 percent. Subsequent changes in setpoints to the present 18 percent were not accompanied with systems upgrades to provide response improvements to compensate for the tighter operating margins. The 14.7-percent level signal widens operating margin and is closer to the original design basis of the system.

Corrective Action for the Feedwater Isolation

Following the isolation, the feedwater isolation signal was reset, jumpers were reinstalled, and testing was successfully completed. As interim corrective action, a training letter will be issued to appropriate maintenance personnel. This training letter will cover this event as a lessons learned and stress the need for double verification of temporary connections (jumpers). A long-term evaluation will be made to determine a more positive method of connecting temporary jumpers.

ADDITIONAL INFORMATION

Since initial criticality, there have been a total of four previous reactor trips resulting from inability to control S/G levels during power operation or following system perturbations. The previous trips did not occur as a result of high-high S/G levels. This was the first trip of Unit 1 in 299 days.

There have been no previous feedwater isolations as a result of an alligator clip-type jumper becoming disengaged from a terminal point. There have been seven LERs previously written as a result of feedwater isolations (SQN 50-327/84033, 85026, 85027, 88041, 88047, SQN 50-328/84017, and 88006).

COMMITMENTS

1. TVA will evaluate the need for No. 3 HDT alarms that will alert the operator of a high or low level in the HDT before the bypass to condenser valves open and before the HDT pumps loose suction because of low tank level. The evaluation will be completed by February 9, 1990.

2. TVA will perform an evaluation to determine if a better method of

connecting temporary jumpers exists by June 22, 1990.

3. A training letter will be issued to appropriate maintenance personnel by February 2, 1990.

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ATTACHMENT 1 TO 9001170353 PAGE 1 OF 1

TENNESSEE VALLEY AUTHORITY
6N 38A Lookout Place
January 9, 1990

U.S. Nuclear Regulatory Commission
ATTN: Document Control Desk
Washington, D.C. 20555

Gentlemen:

TENNESSEE VALLEY AUTHORITY - SEQUOYAH NUCLEAR PLANT UNIT 1 - DOCKET NO.
50-327 - FACILITY OPERATING LICENSE DPR-77 - LICENSEE EVENT REPORT (LER)
50-327/89035

The enclosed LER provides details concerning a high-high steam generator level reactor trip, which resulted from failure of the feedwater regulating valve in Steam Generator 3 to properly isolate at setpoint. Also included in this report are details concerning a subsequent feedwater isolation signal caused by an alligator clip-type jumper becoming disengaged during posttrip testing. These events are being reported in accordance with 10 CFR 50.73, paragraph a.2.iv.

Very truly yours,

TENNESSEE VALLEY AUTHORITY

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